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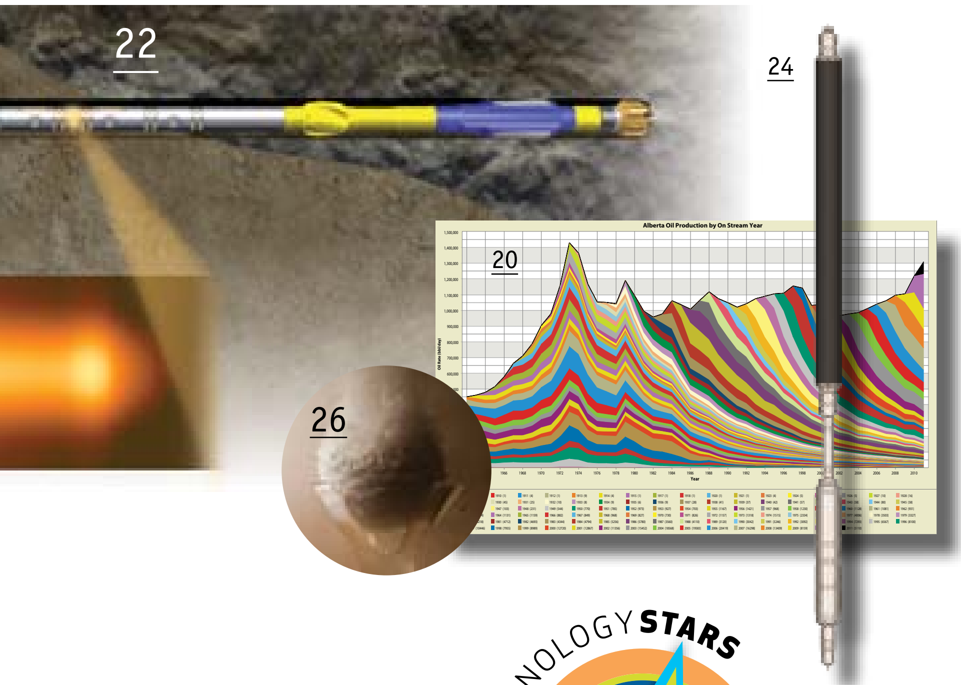

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editor's view

A moving target

A DECADE AGO, CANADA WAS WELL DOWN THE LIST OF countries ranked by oil reserves. Then, in one fell swoop, Canada shot up to second place behind only Saudi Arabia, putting us in the major leagues.

There was no massive new discovery that propelled us there. Rather, it was recognition we had perfected the technology to economically extract a piece of the massive oilsands resource. It became widely recognized that open-pit mining and in situ thermal methods could reliably and profitably access about 10 per cent of that resource. While we couldn't touch Saudi Arabia's estimated 264 billion barrels, our 174 billion carried us past such OPEC heavyweights Iran and Iraq, at 137 billion and 115 billion barrels, respectively.

But after several years of second-place recognition, Canada has quietly sunk to third place this year, at least according to such authorities as the Alberta government and the Canadian Association of Petroleum Producers (CAPP), who were among those pressing to have the oilsands recognized in reserves rankings in the first place.

The country to knock us off our perch, Venezuela, in a sense took a page from Alberta's playbook, gaining recognition for the technological advances—as well as a new assessment of the resource—that have similarly made a big chunk of its massive extra-heavy oil play, the Orinoco oil belt, recoverable.

"What has changed is Venezuela's reported reserves," Greg Stringham, CAPP's vice-president, oil sands and markets, said of the new ranking. "President [Hugo] Chavez came out with their new assessment earlier this year [*Oil & Gas Journal* and U.S. Energy Information Administration] of 211 billion barrels. Since we use these sources for the other countries, we have adjusted our charts accordingly."

It was a major revision, more than doubling the previous assessment of 99.4 billion barrels. It came on the heels of a U.S. Geological Survey assessment in late 2009 of a mean volume of 513 billion barrels of technically recoverable heavy oil in the Orinoco belt, an assessment based in part on the current state of technology in areas such as Alberta.

Of course, a change in ranking doesn't change the fact Canada still holds one of the world's biggest, and certainly most accessible, stockpiles of oil. And it's certainly not permanent either, if the promise of new technology is any indication. Just as technology has opened up 10 per cent of the oilsands thus far, further advancements are sure to open up even more.

Not only that, but the technology required to access another resource still off the books, bitumen carbonates of northern Alberta, is rapidly advancing. The prize is potentially vast. Laricina Energy Ltd., which is among those conducting tests in the region to commercialize the carbonates, says the Grosmont carbonates alone are estimated to hold more 400 billion barrels of in-place bitumen—10 per cent of that would elevate Canada back into second place.

And Canada has one other ace in the hole—the very fact small, innovative companies like Laricina are actively pursuing the resource. Interestingly, it was Maurice Dusseault—a geological engineering professor at the University of Waterloo who authored a paper back in 2001, *Comparing Venezuelan and Canadian Heavy Oil and Tar Sands*—who said then that "many of the Canadian technological developments took place in small oil companies willing to take risks on new ideas. There are very few large multinational corporations that are highly active in the technology developments that have occurred." Whereas Venezuelan development is geared toward large projects executed by multinational companies, "there is great merit in encouraging small company activity in heavy oil development," Dusseault concluded.

Given the pace of technological change, those reserves rankings are likely to represent a moving target. Stay tuned. ■ **Maurice Smith**

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New Technology Magazine is owned by JuneWarren-Nickle's Energy Group, a subsidiary of Glacier Media Inc., and is published 10 times per year. Printed in Canada by PrintWest. ISSN 1480-2147.

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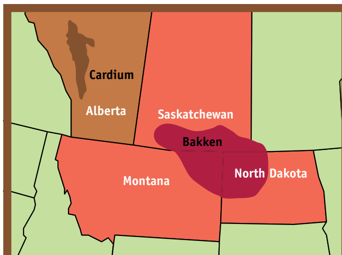

8.36 billion barrels

Low-permeability formations in Canada and the United States made producible with new technology could contain 6.48 billion–8.36 billion barrels of technically recoverable oil, according to James Sorensen, senior research manager at the University of North Dakota's Energy & Environmental Research Center. Contributing the biggest share of the technically recoverable tight oil resource is the Bakken formation of North Dakota, Montana and Saskatchewan with an estimated 3.65 billion–4.3 billion barrels, he told a Calgary conference in October. The second-biggest or the fourth-biggest, depending on whether the low or high range of the estimate is used, is the Cardium formation of Alberta with 660 million–1.89 billion barrels of technically recoverable oil.

$80 per tonne

A price on carbon emissions would have to reach $80 per tonne before it would start to impact natural gas production, predicted Tim Weis, director of renewable energy and efficiency for the Pembina Institute. Speaking to the Conference on the Assessment of Future Energy Systems in November, Weis said that while natural gas production should not be ramped up if governments are looking to address climate change, it will remain an important fuel source for the foreseeable future.

$1 MILLION PER PERSON

The potential value of Alberta's oilsands could be more than $1 million for each and every one of the province's inhabitants, but there is a real risk that resource will be untapped, University of Alberta economist Andrew Leach said in a Calgary lecture last month. Threats to the industry are coming from within Alberta, across Canada, the United States and elsewhere, he said. ***"We have to start thinking about what are the threats to the industry and what will prevent that resource from being extracted, not just how much oil the world is going to use globally."***

Photos: Smokestacks: Photos.com/Jupiterimages; Place setting:Photos.com/Nick Schlax; Oilsands: Joey Podlubny

The oilsands' voracious appetite for natural gas has grown 190 per cent since 2002, more than taking up the slack as industrial demand has fallen elsewhere, according to the Canadian Gas Association. In the same period, demand for natural gas from the pulp and paper, aluminum and steel sectors has dropped by 49, 27 and 14 per cent respectively, the association's Bryan Gormley told a Calgary conference in October. Total industrial demand has grown about 23 per cent.

"The entire 21st century will be dominated by oil, gas and coal."

— Michael Economides, engineering professor at the University of Houston. Speaking at the Conference on the Assessment of Future Energy Systems at the University of Calgary, Economides said a carbon-constrained world is not one the Chinese would ever play along with. "Does anybody in this room believe that there will be economically extractable hydrocarbons in this world that will not be produced because we have legislation in Canada or the United States, which is not going to happen anyway?" he added.

ENVIRONMENT

In The Crosshairs

Cleaning up oilsands won't diminish anti-oilsands campaign, says Keith

CHANGES THAT MAKE OILSANDS production greener—such as cleaning up toxic tailings—won't appease global environmental groups whose real goal is to shut down the industry, says a prominent climate change scholar.

David Keith made the comment last month in an impassioned and provocative speech to a conference held by the University of Calgary's Institute for Sustainable Energy, Environment and Economy (ISEEE). He elaborated in responses to questions at the conference and in an interview with *New Technology Magazine.*

Keith lives in Calgary but travels to Boston, where he has two appointments at Harvard University (professor of applied physics and professor of public policy). In the private sector, Keith is president of Calgary-based start-up Carbon Engineering Ltd., which hopes to develop industrial-scale technologies for extracting CO_2 from the atmosphere.

"The reason that the big NGOs [non-governmental organizations—in this context, environmental groups] want to shut down the oilsands has nothing to do with the local environmental impacts," Keith told the ISEEE conference. "That's just what they say in the tactical battle.... In some ways, it has nothing to do even with carbon intensity. It has to do with a desire to keep that carbon in the ground."

He emphasized that climate change is real and said the economic threat of measures to counteract it should be taken seriously by people who work in the Calgary oilpatch. Keith said he doesn't speak for those environmental groups, but is aware that their ultimate objective is to reduce the total amount of carbon going into the atmosphere.

The former University of Calgary professor wasn't referring to small local environmental groups—who may indeed be satisfied if local pollution is cleaned up—but to big global environmental organizations.

"Their strategic view is they want to stop this production because it represents a huge pool of carbon.... So they want to shut it down. So they don't want to clean it up," he said. But it would be strategically unwise to admit this. "So they'll talk about all the dead ducks and the tailing ponds, and so on. That's just the way politics gets played," Keith said.

He added, "You fix those things, and the desire to shut the oilsands in will not go away."

Keith said process clean up in the oilsands represents "a huge amount of real effort, sincere effort and real progress" by the industry. But he fears it may just be "blood in the water" that motivates the powerful anti-oilsands lobby to "just push harder."

He argued the anti-oilsands lobby is fundamentally different from past environmental campaigns to clean up air and water pollution. In the case of the chemical industry, for example, environmentalists opposed toxic emissions, but not the products being manufactured. Once the process emissions were cleaned up, the clean-air groups were satisfied.

(A more local example would be natural gas flaring. Nearby residents were worried about potential health effects of combustion emissions, so they lobbied against flaring, but not against gas production per se. Opposition subsided as flaring ceased to be a standard industry practice in Alberta.)

In other words, previous campaigns were against the process, not the product. Once the process was cleaned up, those lobbies were satisfied.

"That lesson is not the same as what's going on for oil," Keith said. "The people... who want to close the oilsands business down—they are not fretting about the process. That's just what they say. They are fretting about the product. Because all the carbon in that product is the problem."

So rerouting TransCanada Corporation's proposed Keystone XL pipeline away from the Ogallala aquifer would do nothing to quell the fundamental opposition to the project. Nor will any changes downstream, said Keith. "Once you've sold the hydrocarbons—unless somebody puts them back in the ground—the carbon is going into the air," he said. "There's nothing to do downstream."

But isn't this true for all oil production? And if consumers can't get their oil from the oilsands, it will simply be imported from countries such as Saudi Arabia. So why pick on the oilsands?

Keith believes environmentalists have painted a bull's eye on the oilsands because it represents future supply. Once pools of conventional oil in places like Saudi Arabia have been depleted, unconventional sources such as the oilsands—and later coal-to-liquids technologies—will supply an ever-growing proportion of the world's oil.

"This is the leading edge of global unconventionals. And it's an enormous pool of carbon," he said of the Alberta oilsands.

So will the campaign against the oilsands be successful? "In the long run, there's no question," Keith said.

When pressed for a time frame—whether he thinks the anti-oilsands lobby might be successful within the next 10, 20 or 30 years, he replied: "I think it's more like 30 than 10."

But what would that mean for new capital investment? "I think it's a long time before we likely shut in existing production. [It would take] enormous political pressure and very high carbon prices to actually stop an existing oilsands plant," Keith said. "But... given that [the oilsands sector is] one of the highest-cost producers in the world, and a high-carbon producer, it won't take much to stop new investment. New investment is what really drives this town."

Apart from the short-term impact of an oil price crash, what would it take to shut off new oilsands investment for the long term? Keith offers a couple of possible scenarios.


David Keith

Photo: Ken Bendiktsen/University of Calgary

One would be if Europe and the U.S. adopted some form of a carbon intensity rule like a low-carbon fuel standard. Keith believes there are plenty of moderate Republicans who wouldn't support such a measure now, but may do so in a few years. "And if that happens, this place... will be crushed," he said of Calgary. "That's the reality."

Another scenario would be a rise in the percentage of motor vehicles powered by something other than fuel derived from oil. While Keith predicts electric cars and biofuel vehicles will always occupy niche markets, he nonetheless believes that if their combined share of the global vehicle stock hits 10 per cent and is still rising, then major investors will shift capital to this technology from the oilsands.

But wouldn't the Chinese—who aren't fretting about climate change—still want Alberta's bitumen? Everyone has heard stories or analogies underscoring the nastiness of China's smog-choked air. Surely a country reputed to lack even the most basic air-quality standards isn't going to take climate change seriously?

Keith says his sources indicate that the Chinese leadership already has a plan for how they would de-carbonize, but won't do it until the West moves first.

But if it does decide to act, China can move quickly—first, because it isn't a democracy, and second, because it's run mostly by scientists and engineers who understand the problem, he said.

"They absolutely know that air pollution is their first priority, and that's what they're acting on. That's why things are getting better so fast," Keith said. "Go visit. I was in Shanghai last summer and it was pretty impressive for a city that large."

He said the air-quality improvements that preceded the Beijing Olympics weren't just a flash in the pan; improvements continue at a brisk pace. Emissions from China's coal-fired power plants have been regulated, and many old units have been replaced by new ones with ultra-supercritical technology and scrubbers, he said. And China now has the world's biggest fleet of battery-powered vehicles, though mostly scooters, not cars.

"They have two or three companies like BYD that are absolutely serious about building huge fleets of electric vehicles.... And they're building nuclear reactors at a great pace, and wind turbines and solar at a great pace."

Chinese carmaker BYD, which stands for Build Your Dreams and is partly owned by Warren Buffett's Berkshire Hathaway Inc., plans to export electric cars and buses to the United States, Europe and other overseas markets.

Like India, where climate change is also on the radar, China has a growing middle class, Keith said. "And people here [in Calgary] are blinding themselves if they think that they will never act on climate."

Keith said the underlying core science—that CO_2 levels were rising with consumption of fossil fuels and could cause a climate problem—has been established since the mid-1960s when they were presented to President Lyndon B. Johnson. "It's pretty basic simple science we've known for 50 years," Keith said. ■ **Pat Roche**

DRILLING

Technology's Downside

Junior producers squeezed by technological advances, increased competition

IT'S NO SECRET THAT WESTERN Canada's small producers as a group have been hardest hit by low natural gas prices because of their heavy gas weighting. But the juniors also have been hurt by the disappearance of the income trusts—which increased competition for services—and the shift to expensive horizontal multi-frac wells, which made drilling riskier on a per-well basis.

This was part of the message Adam Gill, an analyst at CIBC World Markets, delivered to a CFA Society breakfast in October. CIBC World Markets estimates that the 2011 gas weighting of Canadian senior producers is at 40 per cent versus 60 per cent oil and natural gas liquids. It found the former trusts that converted to dividend-paying corporations also have a relatively strong oil weighting, though not as much as the senior producers' group.

But the junior producers have the highest gas weighting—which CIBC predicts will average about 52 per cent at year's end, down from about 61 per cent in the first quarter of 2008.

The disappearance of the income trusts—which as a group favoured growth by mergers and acquisitions rather than through the drill bit—forced the juniors to change their business model.

Blessed with legacy oil assets shed by senior producers, the former trusts are focusing on opportunities opened up by advances in horizontal drilling and multistage fracture technology—in other words, focusing on internal growth rather than acquisitions.

This meant the juniors couldn't routinely get bought once they grew to, say, 5,000 barrels of oil equivalent a day, or convert to a trust once they topped 10,000 barrels of oil equivalent a day. The ensuing soft merger and acquisition (M&A) market has forced the small companies to focus more on longer-term internal growth. But this means the juniors are competing head-on with the former trusts for services such as pressure pumping.

Photo: Veer

Gill said dividend-paying corporations (the former trusts) increased capital spending 85 per cent since 2008, while the juniors have increased spending 67 per cent. The juniors now have a much greater need for new capital as they try to finance their growth into intermediate-size companies.

"So now you have larger, better-financed companies...wanting to put more money into the basin, increasing the competition for services," Gill said. "A small company with a smaller budget is finding it harder to compete out there against the larger E&Ps [explorers and producers] who are throwing a lot more money after plays."

In addition to contending with soft gas prices, a tougher business model, a soft M&A market and competition for services, Gill said juniors must contend with a changed risk profile wrought by technological advances. Increasingly long horizontal wells with an ever-increasing number of frac stages has opened up previously inaccessible resources of oil and liquids-rich gas in western Canada.

But with the good news comes increased risk. Relatively expensive horizontal wells now make up a larger percentage of the wells drilled by small producers. "From a risk perspective, this makes a smaller producer more risky on a per-well basis," Gill said.

"You go from [for example] drilling a well that costs $1 million to wells that cost $5 million. You [have, for example,] a $40-million budget. All of a sudden, if you have missteps on one or two wells, you're in a serious situation on meeting your guidance. Whereas if you have a misstep on one or two wells when you're drilling 40 wells, it's not such a big deal." For this reason, Gill is wary of small companies in costly plays.

So how is the market reacting to the challenges facing juniors in this changed business environment? Gill said that since 2008 the market has divided the juniors into "haves" and "have-nots." Criteria for being a "have" include management teams the market loves and hot plays such as the Montney in 2008, the Cardium in 2009 and 2010, and a tight carbonate player today.

Not surprisingly, the "haves" trade at a premium to the "have-nots."

"But what's interesting is you've seen that premium increase," said Gill. "And I think this is reflective of the market understanding that there are bigger challenges for this space than there were in the past. And if you are a 'have-not'—you don't have a hot play with a large inventory [or] your management team isn't maybe as adaptable in horizontal multi-frac wells as maybe the other guys—the market is going to really punish you.

"The premium from 2008 to 2010 was 2.5 times. And now we're seeing the premium between top-tier companies and everybody else spread to five times."

To find bargains, Gill advised investors to search out "have-nots" that the market is undervaluing: "You want to find a value name that can go from being in a 'have-not' position to a 'have' and get that premium."

One criterion for such investments should be a good oil weighting, or oil growth potential. Also, he advised investors to look for producers that have a lower-risk drilling profile than average—for example, juniors drilling wells that cost $2.5 million to $3 million versus those drilling Deep Basin wells costing maybe $5 million to $8 million per well, or $10 million per well in the Duvernay. ■ **Pat Roche**


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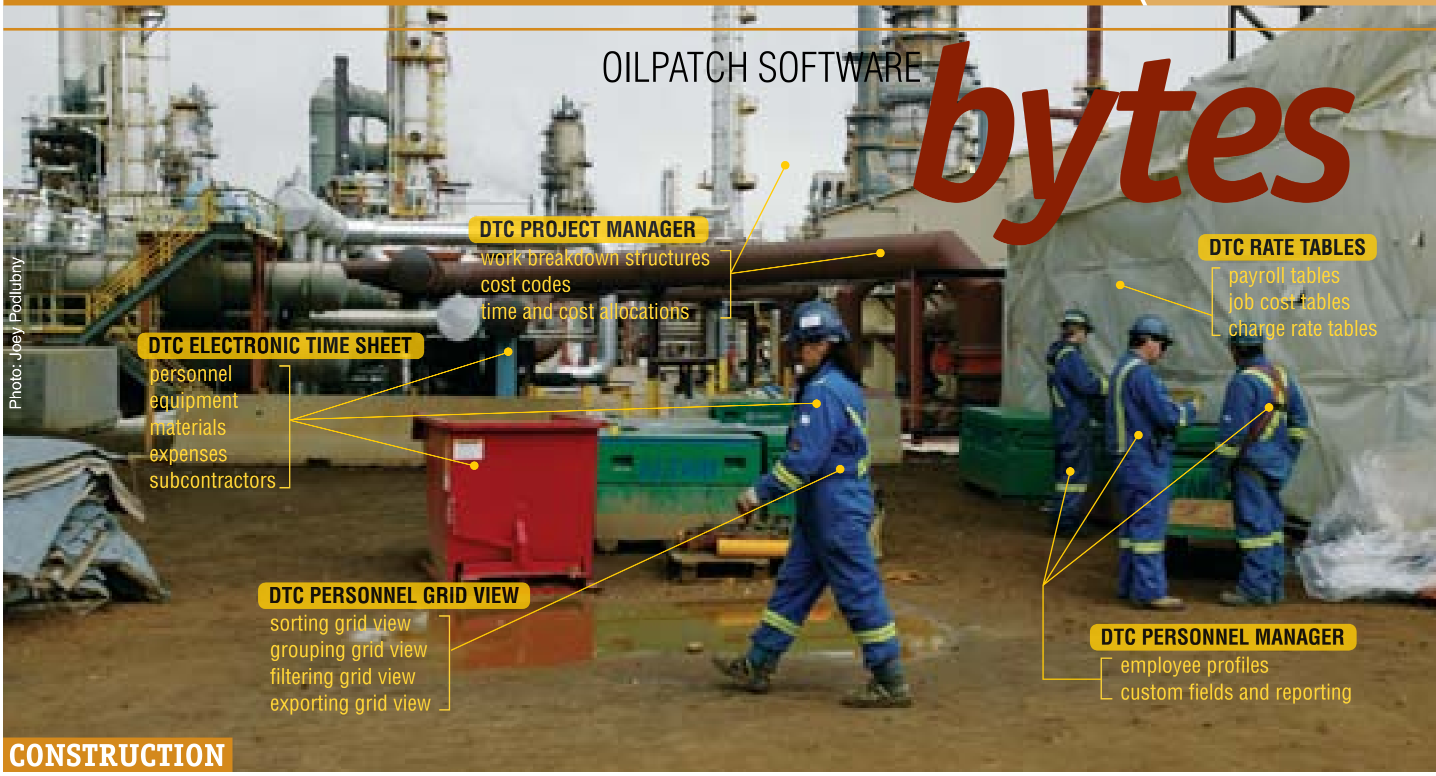

Photo: Joey Podlubny

CONSTRUCTION

A Better Build

Software solution eases the pain of construction contractor field data tracking

IF YOU ARE AN INDUSTRIAL BUILDER, it's hard to imagine a better place to be than Alberta, where healthy growth seems set to continue for decades. The Canadian Association of Petroleum Producers forecasts that oilsands production will double between 2010 and 2020 and reach over 3.7 million barrels per day by 2025. Looking further out, the Canadian Energy Research Institute predicts that output will reach 5.1 million barrels per day by 2042, with total initial capital spending estimated at $257 billion over the next 35 years. And oilsands investment will generate $1.7 trillion in economic activity over the next 25 years, says the Oil Sands Developers Group.

In the past, in particular in the overheated oilsands building boom prior to the 2008-09 recession, massive cost overruns became the norm, sometimes running into the billions of dollars. There are several reasons for blown construction budgets, and an Edmonton company believes it can solve one of them as construction heats up once again.

According to Digital Time Capture Inc. (DTC), millions of dollars are lost every day in the building industry due to construction and financial systems that do not effectively communicate with each other. Its DTC time-tracking and invoicing approach was created to eliminate that deficiency.

The company, which specializes in complex, high-volume project cost tracking, has developed technology that allows companies to track labour, equipment, material and subcontractor information as it happens on site.

"It was created in the vein of trying to give the oil companies what they need, which is the daily cost reports—something we produce out of our software—which is what they ask their contractors to provide," says Scott Cuthbert, DTC's chief executive officer.

"Typically, when oil companies are running megaprojects, where they are spending hundreds of millions or billions of dollars, they can't wait for a company to close off their month end and give them monthly costs. They want to see daily costs, which financial systems aren't very good at doing."

DTC is not replacing companies' financial systems, but rather "essentially extending them out into the field," Cuthbert explains.

Typically, financial systems need to process payroll every two weeks—as well as to receive invoices, issue purchase orders and perform all of the legitimate functions that need to happen in order for them to comply to generally accepted accounting principles, Cuthbert says. "Whereas with our software, we have rates set up, and ▶

KEEPING TRACK
Digital Time Capture's field data capture software can encapsulate the complexities of massive construction projects, such as oilsands megaprojects, into daily cost reports to help ensure they remain on track.

contractors on site can just enter their labour, equipment and materials and we can instantly produce cost reports for them.

"We still need to interface with the financial systems, but we can be much more immediate than a financial system. It helps the owner keep a closer handle on costs, and there are a lot of efficiencies that can be realized. They can certainly reduce their overhead costs, which typically the owner pays for, and for a megaproject, it can save the contractor and the operator a couple of hundred thousand dollars on each job."

And there is the qualitative value of having information immediately versus having to wait two or three weeks, which, while it's more difficult to quantify, creates efficiencies and additional value, he adds. "When their contractor can provide their daily costs, they are able to make management decisions on a daily or a weekly basis rather than on a monthly basis. In a lot of the megaprojects, if you can identify that you are off track early on, you can take some corrective actions that much earlier and stay on track before it's too late."

In constructing a strip mall or a high-rise building, it is relatively easy to visually quantify how much work has been done, Cuthbert says. "But to see the megaprojects at Fort McMurray [Alta.] or the refineries in Strathcona [near Edmonton], it's very difficult to stand there and judge the progress because the job is so complicated. So they really need to be able to break down the costs into really small chunks, which we can do, and then they need to know each day how they are doing against their forecasted progress, which again we can help out with," he says.

"Of course, there are a lot of reasons why cost overruns happen, but the feedback we have received from major oilsands operators like Syncrude [Canada Ltd.] and Suncor [Energy Inc.] is that customers who use our software give them accurate information, which allows them to make good decisions. They can trust that if they are using our software and they are predicting a cost overrun, that it probably is going to be a cost overrun and they need to do something immediately."

In the construction industry, companies tend to see administration and payroll as a necessary evil, Cuthbert says. "They would rather focus on building

Payroll Integration Solution

CH2M HILL, a Denver-based international company involved in consulting, design, operations and program management for government, industrial and energy clients, turned to DTC after it purchased several construction companies and replaced its payroll systems with ADP. It found deficiencies remained, such as the inability to edit time sheet data and updates that were done through ADP—which led to dual maintenance of updates—and the inability to manage or calculate all the necessary pre-payroll items to correctly process parts of its payroll.

A 23,000-employee firm with over $6 billion in annual revenue, CH2M HILL initiated a selection process to find a solution, believing their findings would lead to an in-house resolution. Instead, it found DTC best fit the bill, according to Sam Burgin, CH2M HILL systems analyst. "We entered into a nine-month software selection process, and after screening over a dozen software vendors, we selected DTC as the solution that best fit our requirements for enterprise field data capture," he says.

a plant or doing an expansion or a shutdown than spending their energy doing the payroll side of things. But you can't have 2,000 guys in the field and not pay them on time. Since it's not necessarily an area of comfort or expertise, it does sometimes become a big challenge. We have worked with companies where the owners wouldn't give them any more work because they weren't confident that they could take care of the administrative side of things."

Most of the company's dozen employees have worked in the construction industry and have been out in the field in a finance or operational capacity, so they recognize that DTC can't be a cumbersome, complicated system, he notes. "We need to be very simple, straightforward and intuitive to use and implement. And because we are not trying to be a big financial system, it is a lot easier for us to be more streamlined and user-friendly."

A strategic alliance with Automatic Data Processing, Inc. (ADP) allows DTC to integrate with ADP's payroll service, allowing delivery of a single-sourced solution to highly complex construction payroll.

Electronic time sheets allow for easy entry of personnel, equipment, expenses and subcontractor information into the system, while online access gives project managers and company executives immediate access to up-to-date project information. Security features allow the set-up of access based on company department, position or geographic locations.

The software, built in the Microsoft .NET framework, allows companies to compare estimates to actuals for productivity measurement, to achieve visibility and standardization across projects and to analyze historic information to better estimate future project costs.

Though DTC has no physical presence in the United States, Cuthbert says that, curiously, interest has been stronger south of the border, where the company has clients not only in oil and gas, but in the mining, utilities and nuclear industries. The company has about 35 clients across North America.

"I would say 60 per cent of our customers are out of the U.S.," he says. "It's a little baffling. There are lots of companies right here in Alberta that could really benefit from our software, but it seems like a much more difficult time introducing new technology here."

DTC's technology gave CH2M HILL quick access to its time sheet data and allowed the company to enter its time sheet information through DTC's easy-to-use interface. The system gives CH2M HILL complete control of how the data is handled and allows the company to make any corrections to the data in DTC while maintaining a clear understanding of how the changes will affect its financial system, Oracle Financials, allowing it to manage time sheet data more efficiently, accurately and in volume.

After another client, an unnamed global power-generation company facing challenges managing plant shutdowns, moved to DTC, its mobilization time for new projects was reduced from more than two weeks to three days (installed, configured and up-and-running). The ratio of administrative personnel to field workers was reduced from 1:50 to 1:200, data accuracy was improved by eliminating double keying of information and administrative efficiencies were further improved by reducing the time required for client reporting from four hours to 20 minutes per day, according to the company. ■

Maurice Smith

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Photo: Photos.com/William Berry

TECHNOLOGY STARS 2011

TECHNOLOGY STARS
2011 WINNER

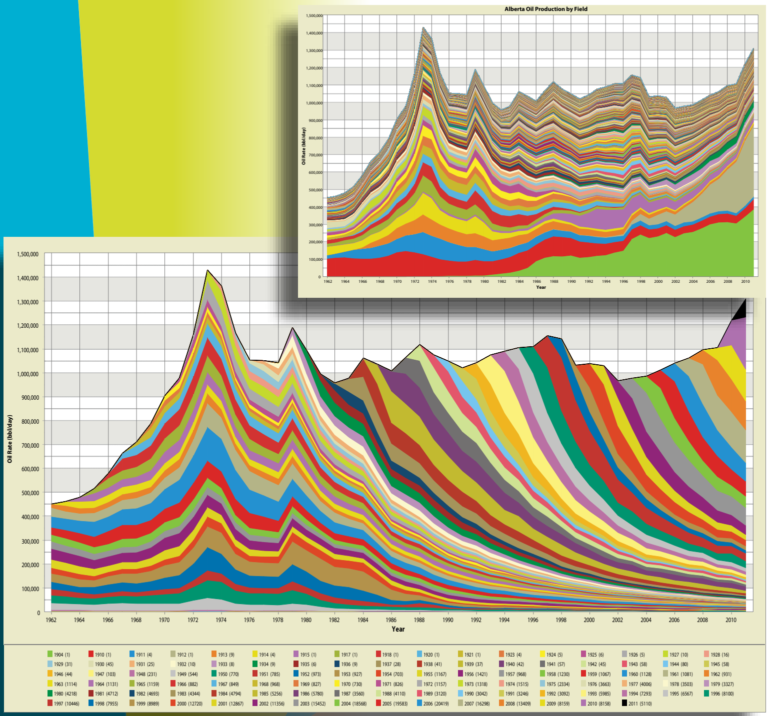
VISAGE information software: a new tool in exploration

Story: Elsie Ross

Best Exploration Technology

VISAGE Information Solutions

mining for data



Top: Alberta oil production by field. Bottom: Alberta oil production by on-stream year.

Launching a new oil and gas company has always been a challenge, but an innovative Calgary-based software company is helping to reduce some of that initial exploration risk.

The tool developed by VISAGE Information Solutions allows for the rapid access, analysis and visual interpretation of more than 710,000 wells in the Western Canadian Sedimentary Basin.

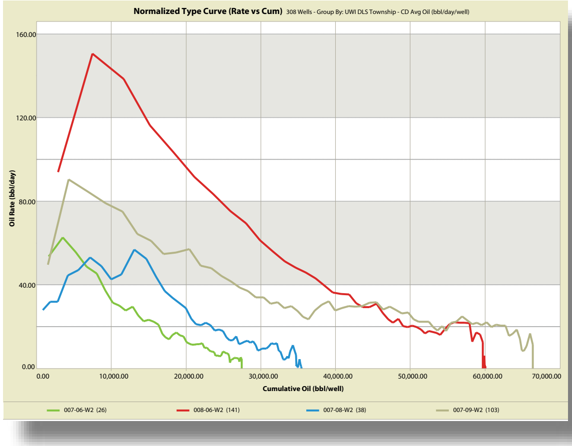
Elkhorn Resources Inc. used that visual analytics technology to screen exploration areas in building its business plan, says Korey Galbraith, vice-president of engineering, who nominated VISAGE as a Technology Star.

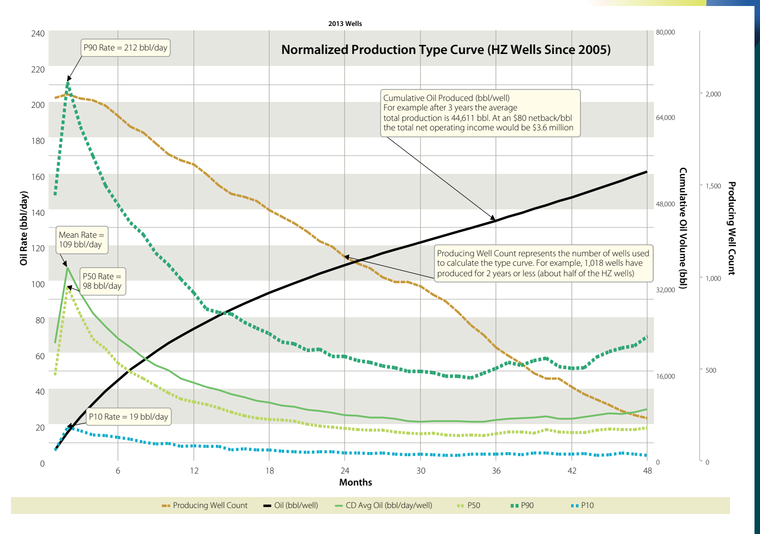
"It's a very powerful tool but very user-friendly," he says. "With the click of a button, we were able to analyze different play types and technical concepts utilizing all publicly available information and all in real time. The VISAGE product enabled us to make quick and accurate decisions that were thoroughly researched and well-founded."

The start-up company had identified the geographic area in which it wanted to operate—Manitoba, southeastern Saskatchewan and North Dakota—and used the software to look at a number of different plays from an engineering perspective to complement the geology. For example, Elkhorn was able to determine the average type curve for a well in the Spearfish play in different settings in order to decide if it was going to become a Spearfish player.

In the end, Elkhorn narrowed its focus to an eight-township area in southeastern Saskatchewan. It identified an area with available land that was prospective for the application of the technology to drive strong economic returns. As an operator, Elkhorn uses the technology to focus in on a particular area and to give it a better understanding of the economics for a potential play type with the actual numbers to back it up, based on public production data.

The type curves, which can be used for building business plans, are good comparison tools and give a representative view of a chart's performance. Chart at right demonstrates statistical methods to quantify the range of possible outcomes.





Images: VISAGE Information Solutions; data by geoLOGIC Data Center

"It's a very, very large data set," says Galbraith. The VISAGE software gives an operator the ability to look at that data and make sense of it, sorting through it and normalizing it against a number of variables.

"I typically will look at 150–200 wells, and it's [in] a matter of less than a minute," he says. "The efficiency of it is real time in my mind with the data sets I am running.

"When you are a small company like ours, every software product has to have a direct cost benefit, which VISAGE definitely does. We run very lean on our staff so we have to make it efficient to be able to do what we need to do, and that's what this tool does."

Because all the plays Elkhorn is involved with are technology-driven, it has benefited from being able to see what other companies have learned in drilling their wells. "It definitely gets you up that [technology] curve quicker," says Galbraith.

Percentile (cumulative probability) distributions provided a comparison of various completions attempted on the target reservoirs, leading to the conclusion that if single-leg horizontal wells could be fracture stimulated, they could yield the same production potential as multi-leg horizontal wells.

The software's ability to generate representative type curves (rate versus time) that can be easily updated has allowed the company more time to actually analyze the data, he says. The results are shared within the multidisciplinary engineering, geology and geophysics team in order to "truth" the technical models.

Another VISAGE innovation is a method of combining cumulative probability distributions with type curves to provide a visual tool to communicate the variability in the production rates that make up type curves.

VISAGE, which was formed by a group of former Schlumberger Canada Ltd. employees, went commercial about 6.5 years ago, says president Bertrand Groulx. Initially, it focused on production operations.

More recently, VISAGE has incorporated into its software the mechanisms that will enable operators to easily and rapidly navigate massive amounts of public information. Exploration and exploitation companies are interested in adding the software as another tool in the exploration process, he says. It can help them find the "hot wells," who is drilling them and what technologies they are using.

Groulx says it would take him less than two minutes, starting from scratch, to bring up all the data for a type curve for the northeastern B.C. Montney formation, based on data from 2,000 Montney wells.

"You are not actually just analyzing data, you are exploring it because once I get those Montney wells up, I can group by company and actually see a type curve by company, and see which is the better company, and that takes literally two seconds," he says. "I can group by drilling contractor and who has drilled the most wells, who has got the best record, and I can look at horizontal length [and] azimuth direction of my wells."

Because of its speed, the tool allows engineers the time to do what they are actually being paid to do: analyze and explore data. "The frustration that I hear from engineers is that they spend the bulk of their time hunting and gathering data—grunt work—and very little time actually doing stuff with it," says Groulx.

He says his company chose a licensing model that would allow it to grow the company while making it palatable and low-risk for clients. "Because we are user-based, we are a rounding error in the grand scheme of things if you want to try out one licence. But if we prove to be very effective, there are some companies where we have [several] users from operators all the way up to the CFO."

Elkhorn has a floating licence so that anyone can use the product, but only one person at a time. "They make it so that the product is affordable for small entities such as ourselves," says Galbraith.

And because the software continues to fund VISAGE's development, "it is constantly getting better, and our 'to-do' list from clients on how to make the tool more powerful never gets shorter," says Groulx. "It will always be evolving." ■

TECHNOLOGY STARS
2011
WINNER

steering straight

Baker Hughes' AziTrak system improves horizontal drilling accuracy

Story: Jacqueline Louie

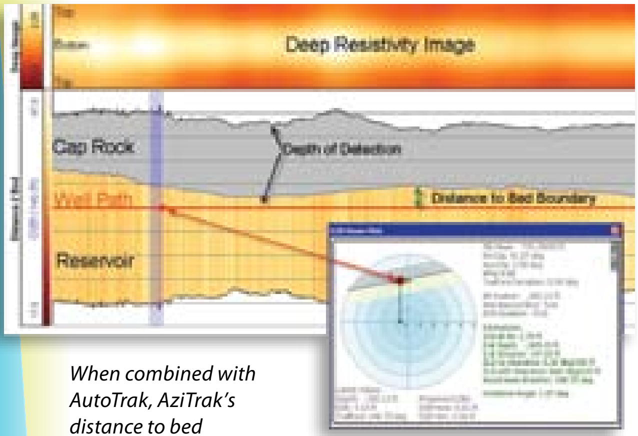
Best Drilling and Completion Technology

Baker Hughes Inc.

Baker Hughes Inc. is helping operators steer their oil and gas reservoirs in the right direction with its deep azimuthal resistivity measurement tool for subsurface navigation.

"We've provided the ultimate GPS for drilling today," says Darren Drake, drilling systems sales manager for Baker Hughes. "We created something that allows you to be forward-looking for the first time ever. This deep-reading resistivity tool allows you to look ahead and steer accordingly—it allows you to see what you couldn't see before. So instead of being in the pay zone some of the time, you can be in the pay zone all of the time."

The Baker Hughes AziTrak deep azimuthal resistivity measurement tool—the Technology Stars' Best Drilling and Completion Technology winner—offers another option for horizontal drilling. It's designed to enhance reservoir performance and efficiency by optimizing wellbore placement in real time, and provide distance to reservoir top and/or bottom, measuring formation resistivities with a deep-reading azimuthal resistivity tool that creates a 3-D image of the subsurface. The AziTrak tool brings a 360-degree view of the downhole environment and provides operators with the capacity to detect, measure and visualize bed boundaries, and detect the oil-water contact in the reservoir hours sooner than when using conventional sensors.



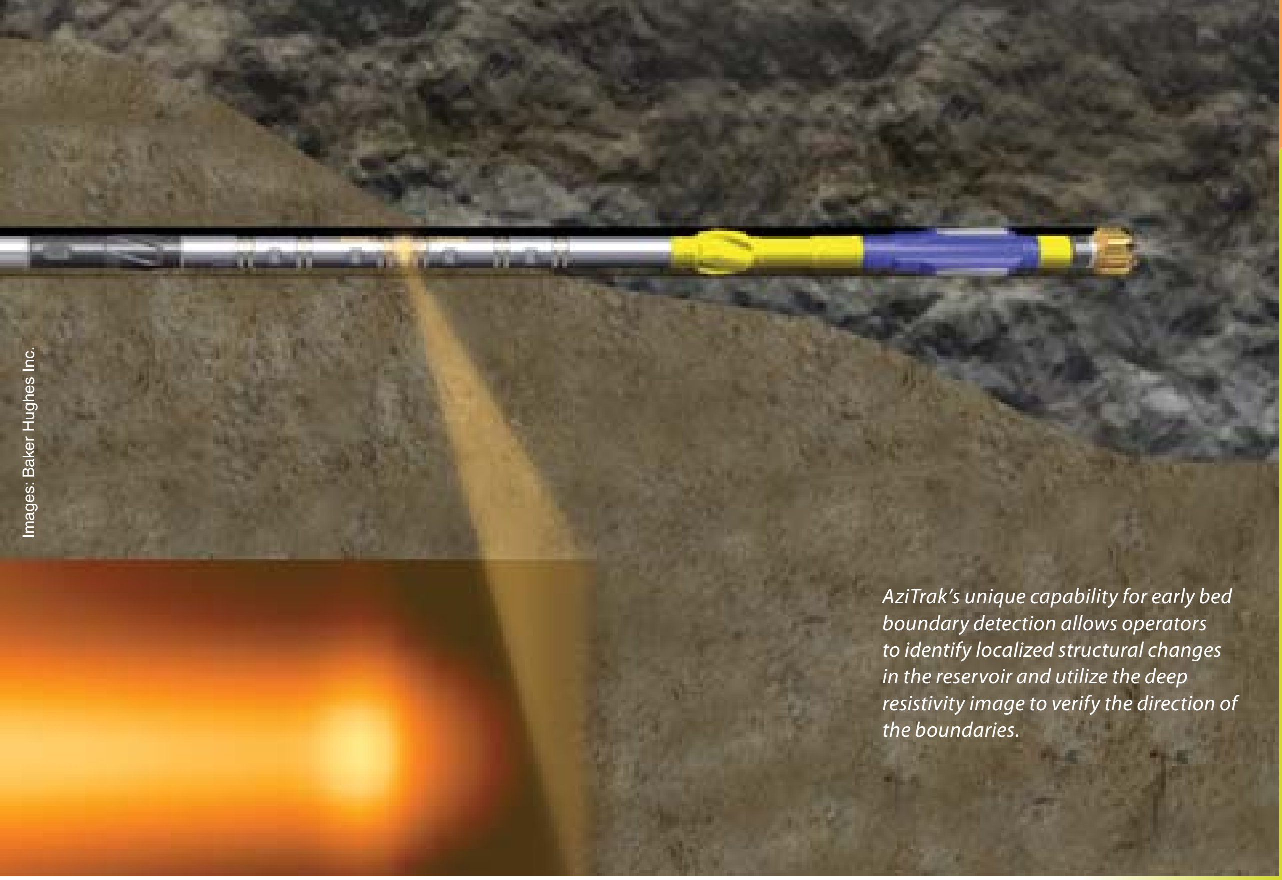
When combined with AutoTrak, AziTrak's distance to bed detection makes it possible for field operators to react to formation dip changes to avoid reservoir exit.

The technology integrates measurement-while-drilling (MWD) and logging-while-drilling (LWD) capabilities into one tool by using multiple-propagation signals and detection for precise navigation data. The Baker Hughes surface tool captures data from all of the downhole MWD/LWD sensors via mud-pulse or wired-pipe telemetry that transmits real-time navigational data and memory-quality images.

When the AziTrak tool is deployed with the Baker Hughes AutoTrak rotary steerable system, field specialists can benefit from the short sensor to bit spacing and apply early steering decisions, such that the wellbore can be optimally placed within the reservoir.

"It's a game-changer," says Adeniyi Ogundana, drilling applications advisor for Baker Hughes. "It's a true proactive geosteering tool because it delivers necessary navigation data in real time and on time. We don't have to wait until we're out of the zone before we react or make a decision.

"Drilling has become more complex. This tool will help companies stay in that sweet spot, even when the zone gets very thin. They are able to stay in



Images: Baker Hughes Inc.

AziTrak's unique capability for early bed boundary detection allows operators to identify localized structural changes in the reservoir and utilize the deep resistivity image to verify the direction of the boundaries.

the reservoir for as long as they plan and have maximum production. You can use the tool to make real-time decisions, but it also stores the collected data in its memory."

The AziTrak tool is one of a very few deep azimuthal resistivity tools available to the market. "Ours is direct measurement. You measure it and that's it," Drake says. "There's a benefit to using a tool that does not require data inversion."

The hurdle for most operators considering this technology, he adds, is the cost—five times that of conventional tools. "The value this tool delivers, however, greatly outweighs the cost. Clients worldwide are sold on the technology's benefits. The people who use it the first time get it very quickly," Drake says. "At the end of the day, it's about money and about best production—and when you have it, people will not go back."

Calgary-based Pradera Resources Inc., a 100 per cent oil-focused junior exploration and production company that chases Slave Point and Gilwood oil in the Slave Lake, Alta., region, had excellent results using the AziTrak tool. Last March, Pradera Resources became the first company in Canada to use the AziTrak tool, in the Slave Point zone north of Slave Lake.

"Deep-reading azimuthal resistivity tools allow us to maximize the amount of the horizontal section of the wellbore within the zone's prime porosity region, for optimization of the wellbore placement," says Daniel Jalbert, vice-president of operations for Pradera Resources. "The technology provides excellent benefits. With the proper interpretation, the tool will enable you to place your wellbore within your zone of interest better than traditional technologies. By placing the wellbore in the optimum position, we get higher production rates, and we've been able to defer the costs of wellbore stimulations until production rates warrant. You end up with a more economic wellbore."

These types of results are reservoir-specific, Jalbert adds. "It won't apply to every zone or reservoir where you run this tool." And, like any other type of technology, he notes, in order to achieve the greatest success the deep azimuthal resistivity tool requires a very high degree of involvement on the operator's part. "Having that level of involvement on the side of the operator is imperative in order to have success with the tool, to optimize the geosteering of the wellbore placement—because it's the geologic interpretation of the results you're getting back that is so critical. It requires a 24-7 team approach to achieve success." ■

TECHNOLOGY STARS
2011 WINNER

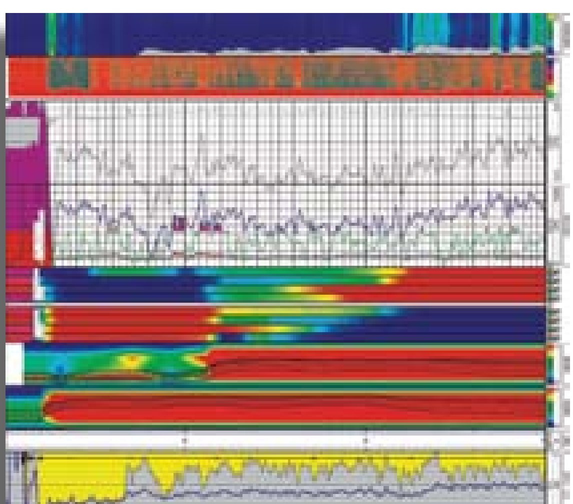
Leak detectives use fibre optics to find even the smallest liquid leaks downhole

Story: James Mahony

Best Production Technology

Hifi Engineering Inc.

amplified leak detection



Images: Hifi Engineering Inc.

Hifi's LeakSonar fibre optic acoustic sensor array is specifically designed to detect and locate fluid migration in wellbores, even through multiple strings of casing.

For oil and gas producers, the "optics" of finding downhole leaks just got a little brighter. Last year, a Calgary-based company rolled out a tool for finding natural gas leaks in wellbores. Since then, industry uptake has been promising, and the team has broadened and refined its fibre optics–based method.

Today, engineers at Hifi Engineering Inc. are applying the same fibre optics tools to the task of finding leaks of liquid in wellbores, says Hifi president John Hull.

Ever since Alberta's Energy Resources Conservation Board (ERCB) turned its attention to leaks, the industry has taken notice. Whether due to casing vent flow or migration, natural gas leaks are a common concern for producers, not least because the ERCB requires them to be monitored and, in some cases, reported.

According to Hull, finding downhole leaks of liquids—as opposed to gas—was usually not a problem, especially at higher volumes, since these are usually easier to detect with traditional tools, such as microphones. But as flow rates decline, the leak becomes harder to detect and, at very low flow rates, it might not be detected at all with conventional methods.

That's a gap Hifi plans to fill with its LeakSonar technology. On the market for a year now, the technology puts specially treated fibre optic line downhole, where it serves both as an acoustic sensor and a transmitter of data. In effect, the fibre optic line becomes an optical "microphone" and a conduit to transmit data uphole, and can be deployed on wireline. Because a fibre optic line becomes the transmission line, much larger amounts of data can be carried than would be the case with wires or cables.

While many fibre optic lines have limited sensitivity, Hifi's proprietary technology converts the line into a super-sensitive sensor capable of detecting very faint sounds that other sensory tools would miss entirely, says Hull, an engineer with fibre optics expertise. Those sounds might include background noise, but they might also include the sounds of low-flow liquid leaks, including water and hydrocarbon liquids.

Hull says LeakSonar represents an order-of-magnitude difference from traditional technology, especially when it comes to acoustic sensitivity. Indeed, he compares Hifi's leak-detecting technology to the high-fidelity, digital music recordings usually found on compact discs.

"Think of it as if you're trying to identify a song, and I give you the best CD out there with headphones, versus an old, scratchy record. If you listen to the CD, you can hear the little things, like cymbal taps, whereas with the scratchy record, you're not going to hear the background sounds, and that's where the clues are," he says. "Anybody can listen to the loud sounds in a well, but it's finding the really hard-to-find 'snaps' or fluid flow" that's important.

"The clues lie in [sounds] that we can't really hear with our ears," he adds. "You can't hear a lot of this stuff with your ears. But if you look at the fibre optic data, you'll notice there's a lot there that we're missing."

While Hull won't say exactly how he treats the fibre optic line to make it sound-sensitive, he acknowledges that LeakSonar technology alters the line and uses its own processing software to interpret the logs when the downhole survey is made. Like other logging technologies, the LeakSonar tool starts at the bottom of the well and is pulled upward slowly on wireline, generating data as it goes.

While logging is ongoing, a section of fibre optic line about 10 metres long is exposed to the wellbore, and it picks up sounds within the wellbore, as well as those outside the casing. For example, the sounds of liquid flowing between the production casing and surface casing would be detectable.

Hifi's LeakSonar tool is only used after a well is completed, or later, when it's producing. While testing is done, all production is stopped, and the production tubing is usually pulled from the well to allow the wireline operator to place the tool into the well.

The real breakthrough achieved by LeakSonar's software is in recognizing the acoustic signature for liquid leaks, including very low-volume leaks too faint to be detected by other tools. Hull describes LeakSonar as "many times more sensitive" than tools like traditional acoustic microphones. In processing the data generated, Hifi's software uses passive sonar technology, he says.

Finding applications for LeakSonar might not take long, and a few major Canadian producers are already using the technology. While shallow gas wells are a common application, there's also a use for LeakSonar in testing steam assisted gravity drainage wells, especially those with very low water flow, Hull says.

Reading the logs resulting from a LeakSonar survey is not difficult. Hull points out that the area shaded in red (see photo) represents a leak of liquid. In the final analysis, the logs also facilitate well remediation. When a leak, whether gas or liquid, is detected, the operator can make repairs by applying a cement squeeze to fill the cracks.

Later, when the cement has had time to set, the operator can run another LeakSonar log to ensure that all leaks have been filled. If not, another cement squeeze can be done to fill the remaining holes. ■

TECHNOLOGY STARS
2011
RUNNER-UP

fixing heavy oil flows

Oilflow Solutions' Proflux cranks up production in heavy oil wells

Story: Jacqueline Louie

Runner-Up
Production Technology

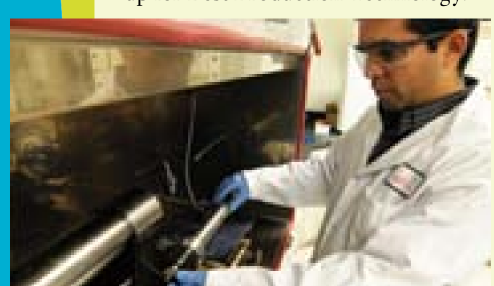
Oilflow Solutions Inc.

Photos: Oilflow Solutions Inc.

Oilflow Solutions Inc. is helping customers enhance heavy oil production, recovery and transmission by resolving viscosity-related issues in wells, reservoirs and pipelines.

"It's unique, patented technologies that mobilize heavy oil," explains Oilflow Solutions chief executive officer Fred Meyer. "As a result, the heavy oil behaves as a lower-viscosity oil."

Since January 2010, the Calgary firm has treated more than a million barrels of heavy oil with Proflux technology—Technology Stars' runner-up for Best Production Technology.



Proflux's chemistry is non-toxic, biodegradable, recyclable and compatible with standard oilfield processes and other industry production chemicals.

The initial development of this unique chemistry was over eight years ago. In 2007, Oilflow established its first Canadian operations and a research and development facility located in Calgary. Since opening operations in Canada, Oilflow has successfully commercialized several products and applications, with more to follow.

In commercial well applications, Alberta's largest heavy oil companies have seen production more than double by utilizing Wellflux in cold production. Jetflux has been used to successfully clean out bitumen and sand from horizontal wells and restore production. Proflux for Workovers helps customers complete their workover operations in steam assisted gravity drainage environments.

The Terraflux reservoir application is undergoing core studies with a major western Canadian oil and gas company, and is also the subject of an independent university study. Initial indications show that the product significantly improves recoverable oil by enhancing enhanced oil recovery polymer technology.

Headquartered in downtown Calgary with a dedicated research and development facility in northeastern Calgary, Oilflow Solutions also has operating bases in Lloydminster, Alta., and Peace River, Alta., to support service and delivery of its applications throughout western Canada.

Internationally, Oilflow is expanding the Wellflux product into the Venezuelan market by partnering with one of the world's largest oilfield service companies.

"Through collaboration with customers and industry, Oilflow's goal is to provide game-changing chemical-based technologies that enhance production and recovery," says Meyer. "Additionally, we want to help resolve issues related to transmission of heavy oil in a cost-effective and environmentally friendly manner." ■

the incredible shrinking ball

Disintegrating frac balls poised to eliminate flowback restrictions

Story: Maurice Smith

Best Completions Technology

Baker Hughes Inc.

TECHNOLOGY STARS 2011 WINNER

The introduction of fracture systems using ball and seat technology to activate downhole sleeves and segregate multiple sections of horizontal wellbores represented a clever innovation to enable multistage fracturing. But if the balls do not flow out of the well after fracturing is completed, they can impede production flow, necessitating the dispatch of a workover rig or coiled tubing unit to mill out the obstruction before production can be optimized.

Now, an oilfield services major thinks it has a solution that is as nifty as the invention of the multistage fracturing technology itself—frac balls just as robust as the originals, but which melt away in the presence of salt water, or brine.

Darryl Firmaniuk, manager of engineering for completion systems in Canada for Baker Hughes Inc., likens them to a candy of his youth. "It's almost like a jawbreaker, where you have it dissolve in your mouth where it eventually disappears."

Called IN-Tallic frac balls, they were designed specifically for formations like the prolific Bakken in the Williston Basin that straddles the border of southern Saskatchewan and North Dakota, where multistage hydraulic fracturing has opened up millions of barrels of new reserves in the past decade.

"If the formation pressure is very low, it can be difficult to get regular frac balls off seat or to flow back to surface," Firmaniuk says. Where production velocity is not high enough, residual frac/formation sand can also pile up in low portions of the wellbore, causing obstructions that further restrict egress of frac balls.

"It depends on your formation and how much residual frac/formation sand you have in your liner after fracturing operations. If a ball is able to come off seat and hits a sand dune on the low side of the well, then the ball may not be able to climb over the sand dune and start moving up the wellbore."

Standard phenolic (typically a resin made of phenol and an aldehyde) frac balls must be able to withstand being fired downhole at speeds of up to 160 kilometres per hour into a stationary seat, and to hold up to pressure differentials during fracking of 10,000 pounds per square inch or more. Thus, they don't break down easily.

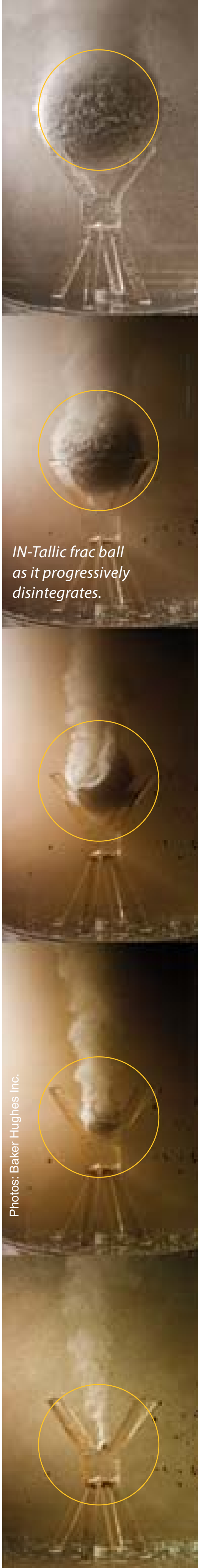
"The regular balls are very robust, very durable in terms of the material they are made of, and they will stay integral for a long, long time," says Firmaniuk. "So we thought about developing a ball that would be able to dissolve enough to come off the seat it landed on to do the frac job, and then it would be able to continue to disintegrate in the liner over time to leave an unobstructed wellbore."

IN-Tallic balls are composed of a proprietary controlled electrolytic metallic nanostructured material—combining specific metallic alloys—that is as light as aluminum but as strong as steel.

Nanostructured materials, built or designed on a nanometre scale—measured in the range of a billionth of a metre—take on properties as defined by quantum physics, potentially making them act in unique ways. According to the company, the IN-Tallic balls' decomposition process works through electrochemical reactions controlled by nanoscale coatings within the composite grain structure.

The balls start with a shiny surface and when exposed to brine, they effervesce "almost like an antacid tablet," describes Firmaniuk. As disintegration takes place, they take on a grainy texture.

The rate of disintegration can vary somewhat depending on such factors



IN-Tallic frac ball as it progressively disintegrates.

Photos: Baker Hughes Inc.

as temperature and the salinity of the fluids present, but generally it should take approximately 24 hours to shrink enough to become unseated, Firmaniuk says. They become pea-sized in about 20 days. Application of acid can speed up that process.

The presence of brine, whether from the slick water frac or from production fluids, acts as the catalyst for the reaction. "Usually the ball doesn't have to get to the size of a pea to come out of the well; the ball only has to get to a small enough size that it's going to not be a problem during the production phase of the well," says Firmaniuk.

While more costly than regular frac balls, they are certainly cheaper than the cost of bringing in a coiled tubing unit to mill out an obstruction, as can be required when regular balls do not flow back to surface.

In multistage fracturing operations where a number of balls are used—consecutively smaller in size as they go deeper into the well—companies have the option to use a mix of phenolic and IN-Tallic balls. Since the smaller phenolic balls are lighter, it most often makes sense to select IN-Tallic balls in the larger sizes, which are less likely to come off seat and flow back up to surface.

IN-Tallic ball sizes range from one-inch to 3.75-inch diameters. They are primarily used in combination with Baker Hughes' FracPoint, the company's main multistage fracturing system in Canada.

After considerable use in the U.S. Bakken and Three Forks formations, Baker Hughes had run one installation for a major operator in Canada and was on the verge of a second run when this article went to press. "From what we know on the first job for this client, the fracturing operations went very well. The balls performed from an impact and a pressure integrity perspective as they were designed," says Firmaniuk.

The company is running laboratory tests to compare results with those in the field (using fluids particular to the Canadian setting), as was done extensively on U.S. trials, and will prepare a case study when all the results are in, he says.

Eventually, the balls are likely to go international, he says. With a specialized technology such as IN-Tallic that works in challenging environments, there is plenty of potential for growth. "Anywhere that water-based fracs are used, and especially where they're combined with low formation pressures where existing balls don't come out of your well very easily, the ball would be of interest." ■

TECHNOLOGY STARS
2011
RUNNER-UP

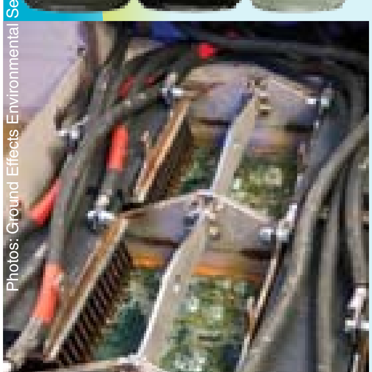
Ground Effects' ElectroPure uses electro-catalytic oxidation to purify produced or flowback water

Story: Maurice Smith

Runner-Up Completions Technology

Ground Effects Environmental Services Inc.

shockingly effective



At the heart of Ground Effects' ElectroPure system, electrocoagulation destabilizes electrical charges and allows coagulation to occur.

Photos: Ground Effects Environmental Services Inc.

An electricity-based, chemical-free technology for treating hydraulic fracturing flowback and produced water introduced by Ground Effects Environmental Services Inc. in 2010 promises to remove 99 per cent of most contaminants while eliminating water transportation costs for the treated volume.

The company's proprietary ElectroPure technology uses a two-stage, vacuum-enhanced electro-catalytic oxidation process to destabilize and remove such contaminants as polymers, total suspended solids, guar gum, iron, scaling agents, bacteria, hydrogen sulphide and almost any other contaminant found in frac water. It has successfully processed some of the most difficult-to-treat types of waste water, including gel and hybrid frac water, says Sean Frisky, founder and president of Ground Effects.

Reuse of the treated water in fracturing operations—which can guzzle up to 70 million litres per frac—eliminates the need, and cost, to replace the treated volume with fresh water, while reducing greenhouse gas emissions. Though not treated to drinking-water quality, it's more than adequate for fracture operations and other industrial uses.

In addition to stationary systems, Regina-based Ground Effects operates six mobile turnkey systems, consisting of three-trailer packages capable of treating from 500 to 3,000 cubic metres of produced or flowback water per day. Two more systems are expected to be in operation this month, with more planned for the future. The systems can be controlled and optimized remotely by satellite or cellular phone link, with real-time critical process information and intelligent trending available.

Recording 99.9 per cent run time, the company's products are known for their reliability. With increasing emphasis on water treatment regulations across North America, Frisky says the company is "well positioned to take this technology forward as the market grows."

In addition to frac water treatment, he says the technology will be applied to produced water and the growing oilsands market for recycling of steam assisted gravity drainage water. "We are getting very good response to the technology. In fact, we are getting interest on a global scale," he says.

Frisky and his company have been the recipients of numerous awards in Ground Effects' 13-year history, including the National Research Council Canadian Innovation Leader award in 2007 and, most recently, the Canadian Environmental Technology Advancement Corp. 2011 Entrepreneur of the Year award. ■

TECHNOLOGY STARS
2011
WINNER

National Oilwell Varco's Dreamcatcher technology recycles old tires into oil spill cleanup products

Story: Jacqueline Louie

Best Health, Safety and Environment Technology

National Oilwell Varco Canada

Before applying Smart Crumb (left) and the result (right).

Photos: Tires: Photos.com/akiyoko; Gravel yard: National Oilwell Varco Canada

a new use for old tires

National Oilwell Varco Canada's Dreamcatcher oil spill technology products and services are saving recycled tires from the landfill—and they're making the planet a greener place at the same time.

Designed to remediate and prevent soil and water contamination, Dreamcatcher's line of patented technologies and services is the Technology Stars' Best Health, Safety and Environment Technology winner.

The technology that all Dreamcatcher products are based on takes a used rubber tire and degrades it into two compounds: the Smart Crumb, a fine rubber crumb used for adsorbing oil spills on land, and Aqua Fiber, a fibre/rubber compound used to adsorb oil spills on water. Both are oleophilic (oil attracting) and hydrophobic (water repelling), which allows them to quickly filter hydrocarbons from water.

After Deamcatcher's Smart Crumb product adsorbs hydrocarbons, it can then be used to produce asphalt products. After the Aqua Fiber is used to adsorb hydrocarbons, it can be remediated and used to replace sand and gravel in residential and commercial concrete and asphalt applications. Dreamcatcher's infused products are lighter and stronger than regular concrete, the company says, and can be used in many common applications including pre-cast paving stones, sidewalks, driveways and roads.

National Oilwell Varco Distribution Services Group is the global distributor of the Dreamcatcher oil spill technology products and services, which were invented and patented by Wayne Bennett, president and founder of ESSI International Environmental Sentry Services Inc., based in Irma, west of Wainwright, Alta.

"The technology designed from recycled rubber tires allows our customers to be proactive or reactive to environmental issues," says Bennett, who has brought 35 years of experience working in the oil industry to his inventions.

"What triggered my research into rubber tires was my desire to create products that could be utilized several times in a cradle-to-grave product. We create the products, we use them for oil spill remediation and, at the end of the day when they can no longer be used for oil spills, we turn them into flexible rubber concrete that does not require sand or gravel. I believe there is nothing like it."

Dreamcatcher's manufactured line of environmental products includes commercial filtration systems used to remove contaminants from water; pipeline spill kits; wellhead bags, used to protect the immediate environment around a producing wellhead; spill response products; truck spill kits and several other products.

In addition to Dreamcatcher, Bennett adds, there are other good products out on the market. However, "the unfortunate part about the majority of them is they are used once and then disposed of and end up in the landfill."

That's something that Dreamcatcher works hard to avoid.

Using recycled tire by-products that would otherwise be landfilled, and not raw materials, helps reduce its environmental footprint.

National Oilwell Varco Distribution Services—an exhibitor at the recent inaugural Global Clean Energy Congress & Exhibition in Calgary—holds the exclusive global distribution rights to the Dreamcatcher oil spill technology products and services. National Oilwell Varco Distribution Services recently created a separate business group focused around alternative energies called NOV EnviroGreen Products and Services, which includes the Dreamcatcher products, solar, wind and environmentally friendly compounds, cleaners and degreasers. "The real value to that is being able to remove waste from landfills, being able to use rubber tires to adsorb hydrocarbons and then recycling them into concrete products so that no waste ever enters landfills," says Shane Exton, product line manager with National Oilwell Varco Distribution Services.

Currently, National Oilwell Varco Distribution Services is working with a number of oil and gas companies to help them meet their frac water filtering needs, by designing a filter to clean and reuse frac water. The ability to closely work with customers is one of National Oilwell Varco's strengths, Exton says. "It's really about how we can work closely with our customers to develop solutions around today's most advanced environmental issues. It's such a new product line, we have the ability to work hand in hand with customers to develop unique solutions around their environmental issues."

Canadian actor, singer and producer Tom Jackson, OC, LLD, chancellor of Trent University in Peterborough, Ont., has been a believer in Dreamcatcher technology from early on and is one of its biggest champions. "Green technology as it relates to this Dreamcatcher brand of technologies will seriously impact the size of the footprint the oil and gas industry has on the globe," says Jackson, who is National Oilwell Varco's Distribution Services vice-president, global business development, based in Canada.

"This technology takes a waste product that is bad for the planet and puts it to use. At the end of the day, the opportunity to further recycle this product into concrete and asphalt products is part of the magic. You take a recycled tire and you put it into asphalt and concrete, and what happens in between is you save the planet." ■

Wellhead bags, packed with Dreamcatcher's Smart Crumb, are easy to apply around a producing wellhead.

Photo: National Oilwell Varco Canada

safety on the square

TECHNOLOGY STARS 2011 RUNNER-UP

Strad Energy Services re-engineers the rig mat to make it safer, more user-friendly

Story: Jacqueline Louie

Runner-Up
Health, Safety and Environment Technology

Strad Energy Services Ltd.

Photos: Strad Energy Services Ltd.

Strad Energy Services Ltd.'s WorkSafe Rig Mat is "a very simple technology, but very effective," says Strad chief operating officer, Rob Grandfield.

Introduced to the market last October, the WorkSafe Rig Mat features a proprietary square tube end made from engineered steel. It was Jared Bathelt, a line foreman at Strad's Nisku, Alta., manufacturing plant, who invented the square end design, which creates a flat working surface with no gap and no rounded edge, reducing tripping hazards at worksites while protecting the ground at the same time.

The Technology Stars' runner-up for Best Health, Safety and Environment Technology, the WorkSafe Rig Mat, "is changing how rig mats are being built," Grandfield says. "It's a safer, more user-friendly rig mat. It doesn't gather mud. It's easier to clean, and it's all-around better."

Traditionally, rig mats have always been built with a rounded pipe end. "It has always been a problem when you butt them up to each other. There's a gap, which is a safety issue, because you can roll your ankle—or it just gathers dirt," Grandfield notes.

Strad's WorkSafe Rig Mat can be used not only at drilling sites, but also at a variety of other locations, including pipeline, construction site and facility access.

In North America, Strad holds 60 per cent of the market share for rig mat manufacturing. The WorkSafe Rig Mat now makes up 80 per cent of the rig mats it sells. Strad can build the WorkSafe Rig Mat to fit any project size; the mats are also available for rent.

"It's just been fantastic—companies have really embraced it," Grandfield says. "We're really proud of it and proud to be recognized as one of the game-changers out there."

Calgary-based Strad provides solutions in drilling-related oilfield equipment and services. The company also supplies servicing and production equipment for the production side of the industry. ■

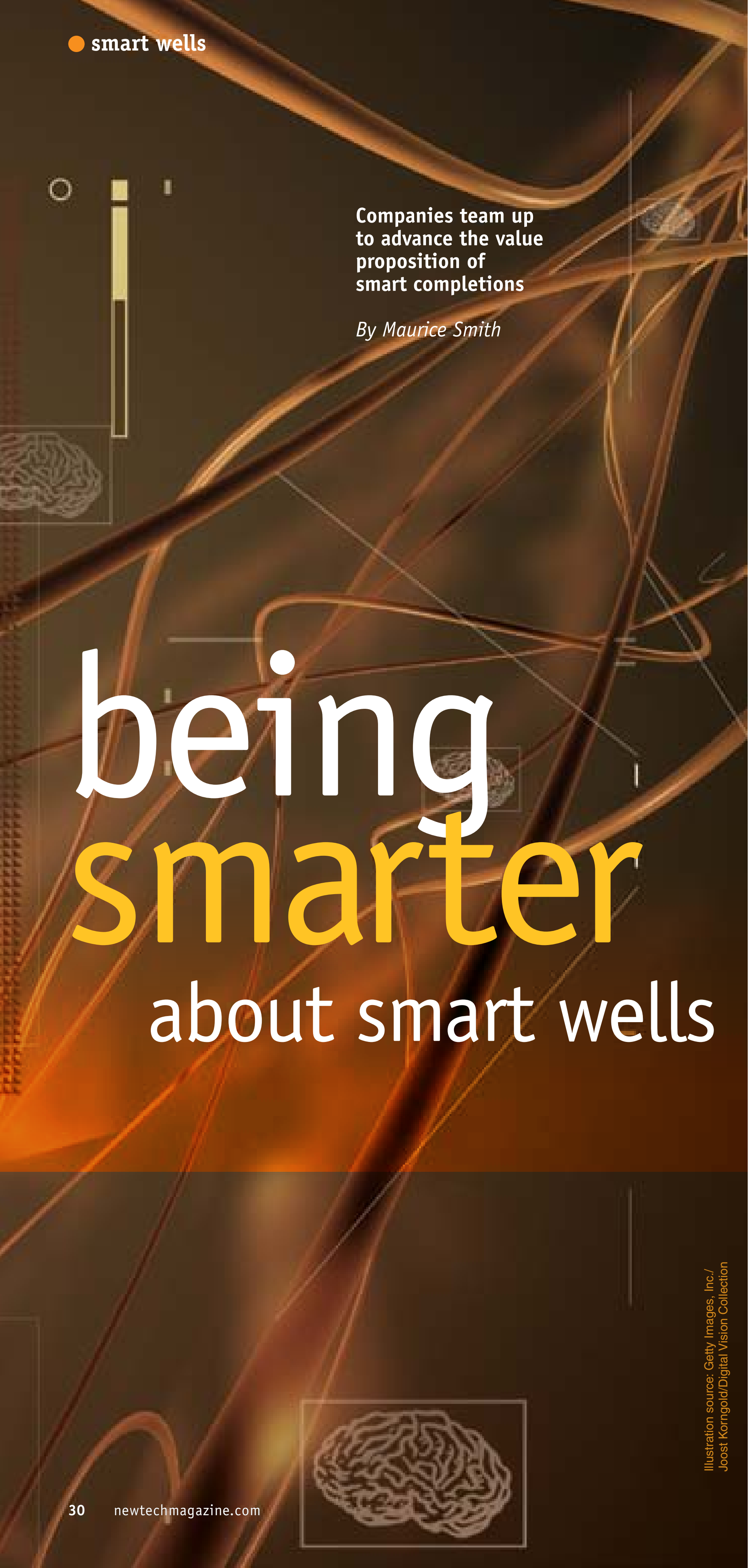


Illustration source: Getty Images, Inc./ Joost Korngold/Digital Vision Collection

Companies team up to advance the value proposition of smart completions

By Maurice Smith

being smarter about smart wells

Smart wells were viewed with much promise as the technology rolled out over the past decade, but after several years in the field, some are asking if the technology has lived up to its potential.

A joint study conducted by partners Shell International Exploration and Production BV, Petroleo Brasileiro S.A. (Petrobras) and Computer Modelling Group Ltd. (CMG) sought to answer that question, and to create the technology going forward that will better allow companies to evaluate the true benefits of its implementation.

Smart wells, also known as intelligent wells and smart completions, are generally defined as those containing downhole measurement and control capabilities, which can be manually or automatically adjusted to optimize production.

With several years of smart well experience now under their belts, the companies undertook a review of how to justify smart well investments and their past benefits, and to improve their ability to predict actual benefits.

They examined about 150 smart wells spread out over some 30 onshore and offshore fields operated by Shell and Petrobras from most major oil and gas productive regions around the world. “We had some from North and South America, some from Europe, from Africa and Asia, even Australia,” says John Hudson, senior production engineer at Shell Canada Limited.

“We were trying to answer two questions; one is, historically why have operators chosen to deploy smart well technology. The second was, what can be improved in terms of making an operator’s life easier in terms of doing the evaluation—how could we get the answers quicker, basically.”

While they may not have entirely lived up to initial expectations, smart wells are now becoming a relatively common development option, Hudson says. “Compared to what they were projecting in 2002 or 2003, it’s been slow, but it’s [still] been exponential—the exponent has been smaller than what was anticipated, but it’s certainly in the thousands of wells now worldwide where we have smart well technology, whereas in 2003 it was in the 10s,” he says.

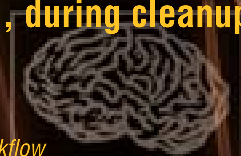
Initially a niche application, smart completions are moving down the value chain. “The cost of a lot of the equipment is actually coming down, the equipment is becoming more standard and it’s being simplified too. I wouldn’t be surprised if in a few years we see smart injection in SAGD [steam assisted gravity drainage] developments, for example.”

Similarly, the ability to evaluate the opportunities and incorporate smart completions has matured in recent years. The means now exists to evaluate aspects that affect profitability and ultimate recovery, such as geological uncertainties, facility design, operational philosophy and procedures and risks.

In the Society of Petroleum Engineers paper *Formalization and Standardization of the Smart Well Modeling Workflow* (SPE 145961), Hudson and co-authors Ibere Alves of Petrobras and Mohammad Khoshkbarchi of CMG note that consideration of such topics “is inherently multidisciplinary, and the quantification of often very detailed technical analysis must be consolidated into an overall [typically economic] ‘model’ that can be used for decisions.... Numerical simulation of the production system has historically played a key role in supporting the required incremental investments for installation and hardware, and these simulations can now include many of the relevant technical factors.”

“Our operating companies have noted significant benefits, including both cost reductions and production improvement, from having deployed smart wells. These benefits can occur during drilling, during cleanup and in production.”

— Society of Petroleum Engineers paper, *Formalization and Standardization of the Smart Well Modeling Workflow*



The study arose out of a larger, five-year research and development project involving the three companies to build a comprehensive simulator of integrated fields involving multiple reservoirs, wells and production facilities. The companies describe it as the newest generation of dynamic reservoir modelling systems (the DRMS project), which to date has been applied to a limited set of producing assets and is expected to be released in a beta version to project partners by the end of 2011.

Some of the most recent study’s findings were unexpected, Hudson says, such as which benefits of smart well technology actually led to the decision to use it. “For example, it turns out that we had quantifiable benefits from being able to optimize the field based on having the downhole control, but we couldn’t find a single example among the 150 or so wells that we looked at where that was counted in the valuation that helped to make the decision. So none of the smart wells were deployed based on production acceleration or optimization.”

The study found the three most important factors for selecting smart wells were reduced lifecycle costs, the ability to assess marginal reserves and improved reservoir management.

Reduced lifecycle costs were often due to a reduced well count to access the same amount of reserves and reduction in planned or risked interventions. In other cases, such as with stacked oil and stacked gas, it was often found smart completions provided a means to access reserves that would be uneconomic using conventional well designs. Improved reservoir management included the ability to control water injection while fracturing and controlling coning or cut-off of gas or water.

Less important drivers that were used to help justify smart wells, but not considered key factors, were production acceleration and optimization, risk management and improved operations.

“Our operating companies have noted significant benefits, including both cost reductions and production improvement, from having deployed smart wells. These benefits can occur during drilling [managing departures from productive zones and mitigating off-normal events], during cleanup [e.g., enabling selective cleanup and during kick off of productive zones] and in production,” the study found, among other benefits.

While modelling applications are much better at addressing the complexity of smart completions in both the reservoir and well context than they were five to 10 years ago—with a number of vendors offering a variety of applications addressing various aspects of the problem—the challenge today has become how to compare and integrate results of various applications so consistent business decisions can be made.

The case study review found that there were a number of opportunities to improve the workflow, including improved scope of integration, enabling the efficient consideration of multiple static model realizations and better integration of reservoir and well modelling for completion design. More efficient handling of uncertainty and design parameters, better integration of enterprise data and improved management of data and computing resources would also help.

The smart well modelling workflow is currently cumbersome, the review concluded, “in that multidisciplinary collaboration is required, yet integration of discipline activities often involves time-consuming steps that are not core engineering activities. Often even simple concepts are not treated consistently across disciplines and applications.”

A better simulator

CMG is the operator of the dynamic reservoir modelling systems project. The company committed approximately $10.6 million to the project in 2006. In August, CMG said it is now anticipating the project will continue beyond the initial five-year time frame, with its share of ongoing funding estimated at $3 million per year.

“It’s quite a large project involving many things, not just smart wells,” says Allan Hiebert, CMG vice-president—DRMS Development. “It’s a very ambitious project.”

The company is reluctant to talk about the simulator while it remains under development. But in a paper presented by Hiebert earlier this year, it was described as a novel and comprehensive framework for simulating fields made up of connected reservoirs, wells and production facilities. The paper notes that the traditional definition of an oil or gas field as a single reservoir and its production and injection facilities is giving way to a wider definition that includes multiple reservoirs that may be in contact with each other.

Today, the worldwide physical assets of a company might be viewed as a single entity, the authors say, “where the various components of that entity are related to each other through natural connections such as faults, through physical equipment such as gathering centres, and through virtual connections such as environmental ►

> **"Therefore, use of an integrated simulation environment where experts from multiple disciplines can test their designs and consistently bring their ideas together can greatly improve the team's efficiency and result in more accurate and timely predictions."**
>
> — Society of Petroleum Engineers paper, *Formalization and Standardization of the Smart Well Modeling Workflow*

constraints on total worldwide production of greenhouse gases."

As extraction of remaining oil and gas resources becomes more complex and costly, simulation of integrated oilfields is becoming increasingly important. But simulating new oilfield design and development methodologies, a multidisciplinary and collaborative exercise, is hindered by limited expert resources and time constraints. "Therefore, use of an integrated simulation environment where experts from multiple disciplines can test their designs and consistently bring their ideas together can greatly improve the team's efficiency and result in more accurate and timely predictions," the paper states.

The DRMS simulator describes an asset as a connected set of physical components, such as a reservoir, a well or a production facility, each of which is represented by a collection of several physical objects such as cells in the reservoir and pipes and separators in the wells and production facilities, according to the most recent paper. Each physical object contains one or more models that mathematically describe the behaviour of the object. "While these objects and their connections can be preserved during the simulation, their models may change. This approach supports representing changes both in the behaviour of the object and in their calculation fidelity."

Equations and variables represent the building blocks of the model as represented in an equation-orientated solver structure. The model is based on what the company calls a Models-Equations-Variables, or MEV, framework that allows for a flexible system that can manipulate general sets of relations between variables and solve the sets of model equations in a high-performance computing system.

Smart well equipment can then be chosen and interconnected, and their mathematical models selected, with each unit representing a node in a connected and undirected graph. "There is no a priori assumption about the direction of the flow from a unit to its neighbouring unit, and the flow directions are determined solely from the solution of the governing mathematical equations representing the physics of the system."

The simulator has so far been applied to both synthetic field examples and currently producing fields of various complexities, including a deepwater subsea gathering centre with multiple reservoirs produced from nine wells and multiple production facilities.

CMG says it expects the first commercial release of the simulator by the end of 2012, with the company and its partners remaining committed to funding its development and to the future success of the project. ■

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EMERGING TECHNOLOGY

An Industrial Lung?

Looking for efficient, affordable CO_2 capture? Check out the human body.

CAN THE ENZYME THAT SCRUBS CO_2 from the human body be whipped into industrial service? A small Quebec City firm believes it has developed technology to do just that, and it has attracted the attention of big players such as the U.S. government and Alcoa Inc., the world's leading aluminum producer.

CO_2 Solution Inc., which says it has 21 employees at its Quebec City headquarters and lab, holds U.S. patents on a process that exploits an enzyme catalyst called carbonic anhydrase (CA). As Jonathan Carley, vice-president of business development, explains it, CA facilitates efficient CO_2 transfer during respiration in humans and other living organisms.

The company hopes to eventually test the technology in the Alberta oilsands and elsewhere in the western Canadian oilpatch. It is already moving ahead with planned pilot tests outside Canada in metals refining and coal-fired power generation.

Its pilot with Alcoa is one of the more unique carbon-capture projects. Instead of pumping CO_2 deep into the earth as a way to remove it from the atmosphere, the Alcoa pilot is designed to convert the CO_2 into a solid product that has commercial uses. In the process, it will neutralize a caustic byproduct of aluminum manufacturing called alkaline clay, or bauxite residue.

Bauxite residue is the highly caustic red sludge that engulfed three Hungarian towns in October 2010 after the retaining wall of an enormous waste-storage reservoir collapsed. Ten people died and about 150 were injured, many with chemical burns. Hundreds were forced from their homes. Earlier this fall, the reservoir's owner, the MAL Hungarian Aluminum Production and Trade Company, was fined the equivalent of about US$647 million.

While this type of disaster is extremely rare, Alcoa said its U.S. pilot program is part of its continuing effort to enhance operational sustainability. ▶

MIMICKING NATURE
CO_2 Solution's carbon capture technology, based on an enzyme catalyst used in human respiration, was developed at the company's Quebec City laboratory.

It will use an Alcoa-developed scrubber technology to capture CO_2 that would otherwise be vented to the atmosphere. The project will test a scrubbing process that combines treated flue gas, enzymes and alkaline clay to create a mineral-rich neutralized product that could be used for environmental reclamation projects.

"The CO_2 is captured in a liquid during the scrubbing process and that liquid is then combined with bauxite residue in mixing tanks where the CO_2 reacts with and is fixed into the bauxite residue," explains Mike Belwood, an Alcoa spokesman. "That has the effect of lowering the pH of bauxite residue, making it useful in other applications such as a construction material."

Scientists and engineers from the Alcoa Technical Center in Pittsburgh will lead the three-year, $16.5-million project, which is supported by $13.5 million in funding from the U.S. Department of Energy's (DOE's) National Energy Technology Laboratory. The DOE grant—which was made available through Washington's economic stimulus program—is part of an initiative to find ways of converting CO_2 into useful products such as fuels, plastics, cement and fertilizers.

"We've just tested at a very small pilot scale with Alcoa. Those tests have just terminated at their Pittsburgh R&D facility. And we'd be looking at testing at one of the refineries in Texas," says CO_2 Solution president and chief executive officer Glenn Kelly.

Photos: CO_2 Solution Inc.

PUT TO THE TEST
CO_2 Solution's prototype reactor has undergone successful trials at Alcoa's Quebec aluminum smelting facility and at a Quebec City waste incinerator.

Plans for the field pilot are still being fine-tuned, but the current time frame would have it up and running in 2013, says Alcoa's Belwood. Also taking part in the project is Redwood City, California-based Codexis, Inc., another small "green technology" firm that has partnered with CO_2 Solution since late 2009 on the development of the enzyme process.

Meanwhile, CO_2 Solution's enzyme-based capture technology isn't limited to rehabilitating red mud. In December 2010, the company announced an agreement with Codexis and a global energy infrastructure company to test its technology for the electricity industry.

CO_2 Solution said the companies agreed to collaborate for up to 16 months on a pilot program to develop and test carbon-capture enzymes and related processes for use in power plants. CO_2 Solution said it would receive up to US$3.4 million in research funding.

The Quebec firm says it isn't allowed to identify its global partner. But right after the announcement the Bloomberg news agency reported the partner is a unit of Alstom SA, which Bloomberg described as the world's third-largest power-equipment maker. Alstom, a French company, did not respond to an email query for this article. On its website, Alstom claims one in four of the world's light bulbs is powered by its technologies.

CO_2 Solution said that agreement resulted from a lab-scale validation effort that showed that the enzyme technology has the potential to significantly increase the efficiency of certain carbon-capture technologies for use in power plants.

Procede Group B.V. of the Netherlands said its testing and process modelling demonstrated the potential to reduce the size of CO_2 absorber columns at coal-fired power plants by more than 90 per cent when the enzyme-based technology was used with methyl diethanolamine (MDEA), a chemical used for amine gas treating. Procede Group's lab tests found that by using the enzyme, the rate of CO_2 absorption in MDEA was increased more than tenfold.

Geert Versteeg, who led the testing at the Procede lab, believes the results represent a potential breakthrough for the economic capture of CO_2 on a large scale.

"This is because the enzyme is an extremely efficient catalyst that enables the use of MDEA and other low-energy solvents for flue gas applications—something that was economically unattainable to date because of the low reactivity of these solvents," Versteeg said in a press release after the tests. "This technology has the potential to transform how the industry looks at solvent-based systems for carbon capture and storage (CCS) from power plants and other large sources of CO_2 emissions."

While shrinking the absorber column size would slash the capital cost of carbon capture, CO_2 Solution believes its technology

would also cut operating costs by reducing energy consumption by at least 30 per cent.

In a conventional amine process, a liquid solvent scrubs the CO_2 out of a gas stream. But where it fails, says CO_2 Solution's Kelly, is to then get the CO_2 out of the solvent quickly and cheaply so it can be injected into the ground. "The [amine solvents] capture the CO_2 quite well…but require tremendous amounts of energy to release the CO_2," he says.

"And that's where our enzyme comes in. We can use solvents that don't require those tremendous amounts of energy. The drawback with [traditional] solvents is they're very slow on capture," Kelly says. By using the enzymes, CO_2 Solution can use solvents that don't require as much energy, he says. "We can speed up capture quite dramatically and use energy-efficient solvents or solvents that don't require all of that energy to release the captured CO_2."

Using traditional technologies to capture CO_2 from coal-fired power plants would enormously increase the cost of power generated at those plants, Kelly says. Along with the cost of compression, this may be one of the reasons carbon capture and storage hasn't taken off. Kelly says the enzyme process would also avoid the undesirable emissions associated with an amine process.

CO_2 Solution also hopes to pilot test its enzyme-based CO_2 capture process in the cement industry and with a western Canadian oil producer, but no agreements had been announced before this article went to press.

One observer who feels the concept "has legs" is Doug Macdonald, a principal consultant with SNC-Lavalin Inc. in Calgary. Macdonald, who over the past decade has led many CCS studies involving proposed facilities in Canada and overseas, sees merit in the idea of using an enzyme to speed up and improve the process of absorbing CO_2 out of a gas stream.

Macdonald, who notes his knowledge of CO_2 Solution is essentially based on public disclosures, also likes what he sees as its realistic approach to problems as development of the technology continues.

For example, he says, "One of their big issues is temperature. Enzymes break down when the temperature goes up.… What I like about them is that they are realistic about that. They understand what their limitations are and they're trying to work on them." The veteran engineer is upbeat about the prospects for the fledgling technology firm: "They've got a good idea, they're moving in the right direction and their eyes are wide open." ■ **Pat Roche**

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PRODUCTION

Doggedly Watching

System helps prevent wells from freezing

Photo: Advanced Flow Technologies Inc.

WINTER WATCH
Advanced Flow Technologies Inc.'s Watch-DOG monitoring system combines wellhead temperature monitoring with Internet technology to forestall well freeze-up.

IN THIS PROTRACTED period of weak natural gas prices, finding ways to maximize revenue by limiting production outages, particularly from shallow natural gas operations during western Canada's bone-chilling winters, is vital to keep operations economically viable.

Temperatures can plunge to -30 degrees Celsius or below and last for an extended period, paralyzing production from wells due to freezing. But automating the monitoring and analyzing the flowing gas temperature allows producers to dramatically reduce wintertime production losses, according to Calgary-based Advanced Flow Technologies Inc. (AFTI), which has developed the Watch-DOG, a lower-cost monitoring system that's currently being tested.

The traditional method of watching for production drops at group meters and then applying methanol has done little to alleviate annual production losses, which can be as high as 15 per cent of winter production, the company reports. Watch-DOG supplies precise information on which wells are likely to freeze, which ones are already frozen and those that are producing normally.

Before Watch-DOG, field operators typically travelled to the field and either applied methanol to the wells they thought might be frozen or applied it to all of them, an expensive, time-consuming and frustrating approach, says Len Johnson, president of AFTI.

"The business problem we want to solve relates to the production losses that producers experience every winter," he says. "Our target market is natural gas producers who have large numbers of shallow gas wells. In Alberta, that's principally south and east of Calgary and Red Deer."

AFTI did a pilot project last year with a major producer and this year is expanding it with a number of producers to test the technology on several hundred wells, which should provide a large enough sample size to show how effective the technology is. To date, Johnson says the product has done its job.

In most shallow gas fields, there's limited electronic equipment to monitor the wells, he explains, adding that producers notice production drops at the measurement points, or group meters.

"They're metering groups of wells," Johnson explains. "There might be 50 wells behind a meter and so they have to try to figure out which of those wells are freezing. It's quite difficult. There's no way to do it, really, except for going to the well.

"What ends up happening is that they suffer production drops that could vary from five to 15 per cent over the wintertime period. It's a fairly significant amount of money. It probably amounts to $70 million to $100 million annually in Alberta."

AFTI says in a white paper that low-cost temperature monitoring at the wellhead combined with intelligent Internet technologies can be both cost-effective and can go a long way to providing producers with the information they need to make decisions that reduce lost wintertime production.

During the frigid winter months, gas wells can freeze over time. Ice forms gradually inside the pipe. In low-flow wells, gas can continue to flow through the pipe until it is almost frozen without producing a noticeable effect on production. This means that workers in the field do not become aware of the effects of freezing until the well is almost completely frozen.

Simple temperature information provides valuable insight into the likelihood a well is going to freeze. Automated

"The business problem we want to solve relates to the production losses that producers experience every winter.... Going from no information to having automated, graphically oriented information will give producers a huge assist in figuring out where to go in the winter."

— Len Johnson, president, Advanced Flow Technologies Inc.

temperature data analysis provides producers with the ability to be proactive about which wellsites to visit. In combination, this information allows producers to not only reduce production losses but also to save considerable time and expense by visiting only wellsites that require remediation.

"For economic reasons, producers have chosen to meter only a small number of the wells," Johnson says. "The WatchDOG technology would cost in the range of $1,200 per well. A traditional meter could cost upwards of $8,000 or $10,000 by the time it's installed. Our device is…a lower-cost choice."

AFTI installs a probe inside the pipe, which is attached to a box that contains a computer, satellite modem and battery.

"We collect the temperature data and periodically, we send all the data we've collected to our website," Johnson says. "On the website, the producer would be looking at a map of the area and showing the pipelines plus the location of our units.

"They can immediately see which wells they have monitored. We analyze the incoming data and we can tell them whether the well is flowing normally, whether it is showing a temperature behaviour that makes it likely that it will freeze or whether it's showing temperature behaviour that indicates it's already frozen."

These are indicated by the traditional traffic light colours: green means the well is flowing normally; yellow indicates it's likely to freeze and red shows the well is already frozen.

"Going from no information to having automated, graphically oriented information will give producers a huge assist in figuring out where to go in the winter," Johnson says. ■

Richard Macedo

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Images: H_2Safety Services Inc.

HEALTH & SAFETY

When Time Is Of The Essence

Software specific to industry calls out to public safety

OPERATING HUNDREDS of kilometres of pipelines and many processing facilities—mostly sour gas—with as many as 1,600-plus people living around them, Keyera Corp. spent years searching for the perfect software system to handle emergency responses.

The Calgary-based midstream company found it in H_2Safety Services Inc.'s Mapping and Response System (MARS). It has been using the program for the past year. So far, it's only been needed for non-emergencies such as flaring notifications, but Keyera is "extremely happy" with it, says Scott Turner, Keyera's community response coordinator.

"When you're trying to critically determine where an emergency is and the impact on the public and who the key people are that you need to identify very quickly—and isolate which ones are critical to shelter or evacuate—this program helps to get through all that data very quickly and is able to share it," says Turner.

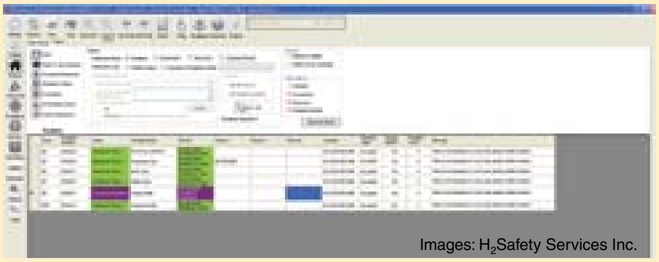
Keyera's previous provider's data had to be manually manipulated, whereas MARS automatically does it all at the same time, reducing the amount of manpower needed, he says. "It's just a really good all-round tool for helping with public safety."

MARS saves at least an hour when time is very precious, he says. "We're able to get answers within seconds, half a minute, for something that used to take half an hour for as few as 30 or 40 residents. In public safety, this is critical."

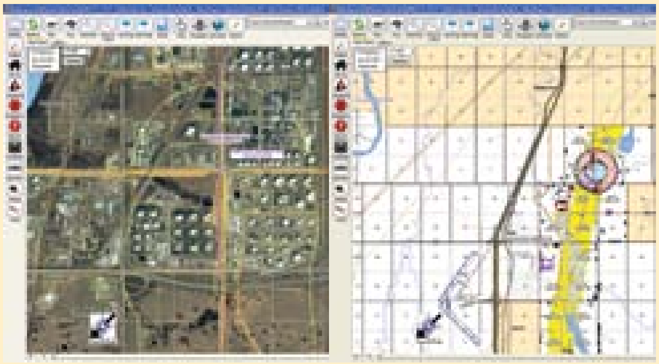
All oil and gas companies are required to have comprehensive emergency-response plans that include procedures for notifying the public, mobilizing response personnel and agencies, and for establishing communication and coordination among the parties involved.

The Windows-based software program, designed specifically for the oil and gas industry and emergency-response scenarios using industry and regulator feedback, is a combination of a graphical mapping tool and an automated callout tool.

The user is able to see the emergency situation on a map, and MARS will automatically identify all the affected residents and area users, who will then be notified by the automated callout tool with either a pre-recorded or fully customizable message. ▶



Images: H_2Safety Services Inc.



RISK MANAGEMENT
Mapping and Response System information screens including (clockwise from top): Callouts-residents; planning zone and satellite map.

"We're able to take response [times] from hours to minutes and do it with a much higher degree of accuracy than we could before," says James Harasen, H_2Safety's president and chief executive officer. H_2Safety provides emergency response management and other health, safety and environment services.

The automated callout system is designed to initiate hundreds of phone calls in under a minute. He says MARS successfully notified 2,000 people in less than five minutes in a test. The system can pinpoint the people users want to notify and can track who's been notified.

As calls are made and responses are received, MARS will automatically update the status of these people visually on the map so that users—public safety coordinators or supervisors—will know immediately whether people have sheltered-in-place, evacuated or require additional assistance.

Photo: H_2Safety Services Inc.

To deploy responders and keep all company officers updated, MARS can store all internal company data and automatically inform them with customizable messages. The software provides a complete picture of the hazard area, including all roads, oil and gas operations, rivers, creeks and streams, as well as topography and satellite imagery. It can be set to training, exercise or emergency mode to allow responders to train and conduct exercises with the same fully functioning, interactive tool they would be using in a real emergency.

Unlike other systems, it works with or without an Internet connection. "A good chunk of what's going on is in the northern part of the province, where cell or Internet coverage is selective. Our system doesn't require Internet coverage to run the entire system," says Harasen.

MARS allows the user to quickly change both the size and shape of emergency planning zones and manage emergency resources such as roadblocks and air monitors. It will constantly update the status of any emergency. It provides up-to-the-minute updates, instant map refreshes, tracking of phone calls and a retained log of all actions.

Callout messages can be predefined or customized to suit particular requirements—for example, initial isolation, protective action and emergency-planning zones can be assigned different messages simultaneously. The people notified will be given clear direction on what to do and are able to provide an immediate response of acknowledgement, request assistance or speak to a company representative. Callout can be used for residents, government agencies, area users, company internal or any other user-defined callout group.

The graphical mapping feature even allows users to incorporate wind direction. All actions are logged and stored for regulatory audits.

Since being commercially launched in mid-2010, just a handful of companies have signed on with MARS and, so far, none have had to employ it in an actual emergency. Penetration has been slower than expected, but the response from companies that have used it has been "incredibly good," says Harasen. ■ **Lynda Harrison**

CONTACT FOR MORE INFORMATION

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